Trip and Restore Distribution Circuits at Transmission Speeds

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I. Introduction

Power engineers devote significant time, effort, and attention to monitoring and measuring power quality on distribution systems. Of particular concern are the duration and severity of voltage dips and the length of time to restore service following an outage. This paper addresses protection and control means of reducing the root cause of these power quality issues.

Overcurrent elements, voltage checks, and line switch statuses provide important data about the distribution system. Linking protection systems together by communications allows these systems to use this data for faster fault isolation—this translates into less voltage sag time for customers served by nonfaulted lines in the surrounding power system.

Knowing which line section is faulted also lets us create intelligent reclosing and load transfer schemes. Integrating this knowledge into the protection system avoids the "process of elimination" method of load restoration. Avoiding this method of load restoration saves maintenance dollars by reducing breaker, recloser, and line-sectionalizer operations. More importantly, this method of load restoration maximizes the power quality of those customers not served by the faulted distribution circuit.

II. Are Traditional Indices a True Picture of Actual Service Reliability?

Utilities use service reliability indices as a measure of customer satisfaction. These indices are typically based upon the number of customers per outage and the outage duration. Table I lists the definitions of the most commonly used distribution service reliability indices.

From Table I, the average cumulative time a customer can expect to be without service is about 100 minutes per year using the SAIDI index. The average number of times a given customer can expect an outage is about 1.20 outages per year using the SAIFI index. The average outage duration (CAIDI) is about 80 minutes. The last number is the ratio of the available service duration to the demanded service duration (ASAI).

An important point to note about the survey is that most utilities do not classify an interruption as an "outage" until its duration exceeds about 5 minutes. This classification of interruptions also does not address voltage sag induced load interruptions on distribution lines adjacent to the faulted line.

No matter how high we believe an existing service reliability to be, the increasing voltage sag sensitivity of loads should motivate us to review new methods of improving service reliability. These new methods must reduce fault duration and minimize voltage sags on nonfaulted circuits.

Table I
Traditional Reliability Indices

Index[1]		1990 Survey Results	Index Calculation
1	SAIDI[2]	96 min per year	Σ (Outage Duration) • (Customers Affected) / Total Customers
2	SAIFI[3]	1.18 int. per yr.	Customers Interrupted • (No. Interruptions) / Total Customers
3	CAIDI[4]	77 min per int.	Σ Customer Interruption Durations / Number of Customer Interruptions
4	ASAI	0.999375	Customer Hours Service Availability / Customer Hours Service Demand

1. Utilities use numerous other indices, but these are the most popular, based on a 1990 survey [4].
2. While this index does consider outage duration, the traditional minimum duration is 5 minutes (this index does not observe interruptions that are less than 5 minutes in duration).
3. This index does not consider outage duration (5 and 20 minute outages are treated the same).
4. This index is really SAIDI/SAIFI. The numbers are slightly different because not all utilities reported both SAIDI and SAIFI.

III. Minimizing Load-Service Unavailability

For distribution substations served by a single transmission line, any permanent transmission line fault interrupts all distribution power until the line is restored. Adding another transmission feed to the substation decreases the likelihood of this possibility. If the substation load is important enough, the cost of installing, maintaining, and operating a second transmission line is justifiable. This same philosophy applies to radial distribution networks: important loads must have an alternate feed in case the primary feed experiences a permanent fault.

When we consider providing an alternate feed, how much can we expect to improve service reliability and what measures can we use? In the following section, we use fault tree analysis to compare the service reliability for two separate cases:

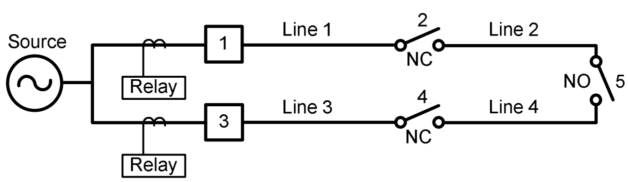
- Case 1: Using manually operated line isolation switches.
- Case 2: Using automatic restoration.

A. Case 1: Using Manually Operated Line Isolators

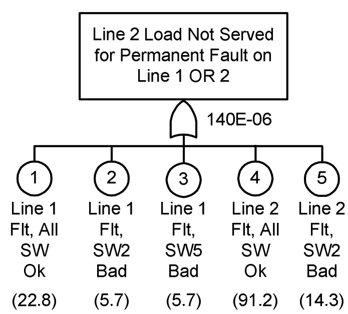
Fig. 1.a shows a two-line radial distribution network with three manually operated switches for line segregation and load transfer. Given a permanent fault on Line 1, the relaying for Switch 1 (SW1) trips and all load on Lines 1 and 2 is interrupted. To restore load to Line 2, operators must manually open SW2 and then close SW5. In this example, we assume it takes an operator one-half hour to reach and operate each manual switch sequentially. Thus, Line 2 load is restored one hour after the permanent fault is cleared by SW1.

Load on Line 2 is unserved until SW2 and SW5 operate after a permanent fault on Line 2. Line 2 load goes unserved longer if SW2 or SW5 are defective. This same load is unserved for permanent faults on Line 2.

Fig. 1.b shows the fault tree and resulting unavailability calculation results for the assumed failure rate and MTTR values shown in Table II. Appendix 1 shows the calculations used to arrive at the unavailability values used in the fault tree base events. For simplicity, let us restrict the evaluated failures to those of faults on Lines 1 and 2 and of the manually operated switches. (We have intentionally not considered SW1 breaker failures for the example system because this event requires tripping the incoming source breaker, thereby removing all possible sources of power to Line 2.)



a. System Single-Line Diagram – Manual Isolation Switches



b. Unavailability of Serving Line 2 Load – Manual Isolation Switches

Fig. 1. Single-Line Diagram and Unavailability Fault Tree for Distribution System Using Manually Operated Line Isolators

TABLE II
ASSUMED FAILURE RATES AND MEAN-TIME-TO-REPAIR (MTTR)

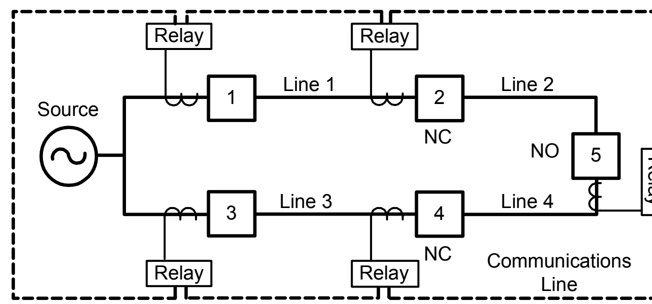
Apparatus	λ (Failure Rate/Year)	MTTR [Hours]
Line Section	0.20	3
Breakers and Switches	0.01	1

B. Case 2: Using Automated Fault Interrupting Devices to Isolate the Line Sections

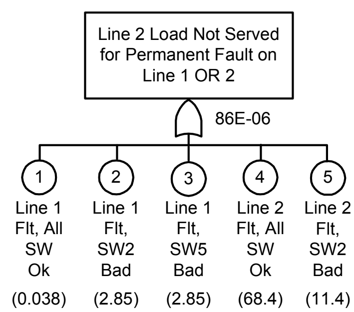
Is the switching arrangement shown in Fig. 1.a optimal in minimizing the outage duration for loads served by Line 2?

Let us next look at replacing the manual switches with automatically controlled fault interrupting devices (i.e., electronic reclosers, breakers, and so on) Further, let us assume that the protection supplied for all of the breakers and automatic switches is linked together via a communications link: point-to-point radios, fiber-optics, and so on.

Fig. 2.a shows the same distribution network with automatically controlled switches and the associated overcurrent protection and control scheme. The communications link dramatically advances the automation and control possibilities. Examples of the advanced control are discussed later in this paper. For the purpose of this example, we assume that each protective relay shown in Fig. 2.a communicates with the adjacent relays with control functions. This capability allows fast automatic restoration and avoids dispatching an operator to restore load. Most importantly, it saves approximately one hour in restoring service to Line 2 load.



a. System Single-Line Diagram – Automatic Isolation Switches



b. Unavailability of Serving Line 2 Load – Automatic Switches

Fig. 2. Single-Line Diagram and Unavailability Fault Tree for Distribution System Using Automatically Controlled, Fault-Clearing Line Isolators

Again, let us assume a permanent fault on Line 1. For a fault on this line, the protection for SW1 trips nearly instantaneous, and the internal recloser attempts an unsuccessful reclose 5 seconds later. Approximately 1 second later, the relaying for SW2 opens SW2, and then the relaying for SW5 closes SW5.

Fig. 2.b shows the fault tree and unavailability calculation results for the assumed failure rate and MTTR values shown in Table II. Appendix 1 shows the calculations used to arrive at this unavailability value. From Fig. 2.b, notice that the unavailability of the automatically controlled switch scheme is decreased considerably: a 40 percent reduction! The costs required to achieve this reduction must be weighed against the value of increased service reliability for customer loads.

IV. Power Quality Justification for Adding Equipment

The previous example shows that adding automated fault interrupting and closing apparatus decreases Line 2 load unavailability for Line 1 faults. In our Case 2 example, we "assumed" that the Line 2 load could "ride through" a 6-second interruption (5-second open interval plus a 1-second transfer switching operation). What if the load connected to Line 2 was such that the 6-second service interruption caused total plant shutdowns?

Reference [1] summarizes a survey of critical service loss durations for industrial plants: 25 percent of industrial plants must completely restart production if service is interrupted for more than 10 cycles. Considering that the time to restart many of these industrial plants is long (average time greater than 17 hours!), we must consider the customer-incurred cost for what might seem a short service interruption.

The switching and associated scheme suggested in Fig. 2.a obviously does not prevent a shutdown of the plant in the 25th percentile. There are two reasons why the proposed scheme is insufficient:

1. The transfer time is excessive (Line 2 load is unserved for 6 seconds after SW1 opens).
2. The distribution bus voltage is still depressed due to the presence of the fault on Line 1. This depressed voltage condition is called a voltage variation.

A. Acceptable Voltage Variation Durations Depend Upon the Type of Connected Load

Not every voltage variation is intolerable. The tolerability depends upon the type of load, percent voltage deviation from nominal, duration, and time between variations.

For a given load, we can use power acceptability curves to determine whether or not a singular voltage variation is tolerable. Fig. 3 shows a typical power acceptance curve. The ordinate of power acceptability plots is scaled in percent of nominal voltage; the abscissa shows voltage variation duration. From Fig. 3, a voltage variation is tolerable (i.e., sensitive equipment can ride through the voltage variation) if the point defined by the measured percent deviation from nominal and time duration is between both curves shown. Points above or below these curves indicate an unacceptable voltage variation for a singular voltage variation.

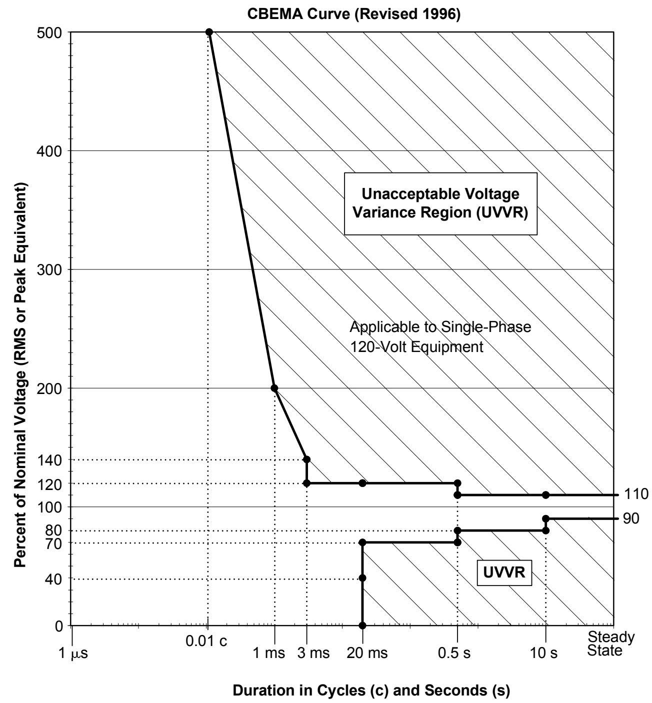


Fig. 3. A Power Acceptability Curve [3]

These power acceptability curves are also referred to as CBEMA (Computer Business Electrical Manufacturers Association) and FIPS (Federal Information Processing Standard) curves. There is no universal standard for power acceptability curves. The reasons for this include:

- Different loads have different tolerances to voltage variations. This means that we cannot use a "standard curve."
- Power acceptability curves do not consider multiple voltage variations that occur in rapid succession. A single voltage variation may very well be tolerable, but a second voltage variation that occurs very close to the first may not be tolerable. Power acceptability curves do not account for load recovery time. Call the recovery time T_r.

We can deduce from Fig. 3 that reducing the duration of a voltage variation permits a greater deviation from the magnitude from nominal before a variation becomes intolerable.

Every load has a recovery time (T_r) for voltage variations. As an example, household air conditioner compressor motors often have a 20 to 30 second T_r for voltage sags, which reduce the phase voltage to less than 60 percent of nominal.

The value of T_r depends upon the severity and duration of the voltage variation. T_r also depends upon whether or not the voltage variation is an interruption/sag or swell. If the load does not experience another voltage variation for time T_r following the initial voltage variation, the load fully recovers. If another voltage variation occurs during time T_r, the load might not recover. It is this point that is not illustrated by the typical power acceptance curves. A better way to decide whether or not voltage variations are acceptable is to superimpose loci of constant values of recovery times. By avoiding the second compounding voltage variation, we can also avoid having to concern ourselves with these load recovery times.

Voltage variation tolerance is dictated by the most sensitive load on a particular circuit. Thus, only the recovery time of that load needs to be superimposed on the power acceptability curve. Also note that voltage variations of the same deviation from nominal but of a longer duration require longer recovery times.

B. System Configuration Affects Voltage Variations

From the previous section, we see that for voltage variation-sensitive loads, we must trip the faulted line and restore supply to the load from an unfaulted source in a matter of cycles. How the system is configured can either reduce or compound the effect of voltage variations.

Many distribution stations include multiple power transformers. Fig. 4 shows the same distribution line network as shown in Fig. 2.a, but now served by two power transformers (XFMRs A and B). For this example, we assume that Switch C is normally closed, and Line 1 experiences a three-phase fault close to SW1. For this fault, all four line sections experience a voltage sag. By opening SWC and SW2 for this fault, we immediately raise the voltage on Lines 3 and 4.

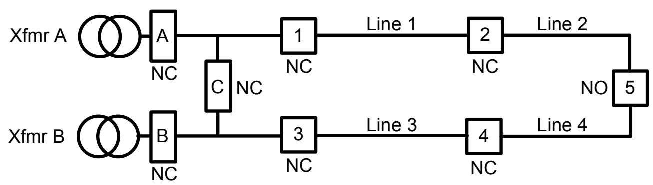


Fig. 4. System Single-Line Diagram (Two Source Transformers)

Fig. 5 illustrates why separating the source bus raises the voltage to Line 3 for a fault on Line 1. The dashed line in Fig. 5 represents the sequence connection diagram before opening SWC. To see how much of a voltage rise we can achieve, let us assume the following system values:

1. Transmission voltage = 115 kV; distribution voltage = 12.47 kV
2. XFMR A and B positive-sequence impedance (Z1A and Z1B, respectively) = 10.58 Ω secondary (115 kV base)
3. Positive-sequence source impedance = 1 Ω secondary (115 kV base).

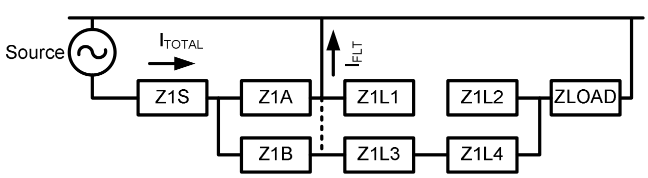


Fig. 5. Sequence Connection Diagram (Two Source Transformers)

For this three-phase fault, the voltage presented to all four lines is obviously zero. With SWC open, the total fault current flowing through XFMR A is 5.7 A secondary (66.4 V / 11.58 Ω). Thus, the voltage present at the high side of XFMR B is 60.67 V secondary (66.4 V – 5.7 A • 1 Ω) or 91.4 percent of nominal. This voltage level is acceptable because the source impedance is small. However, increasing the source impedance also increases the source voltage drop. If the source impedance is instead 10 Ω, the high-side voltage of XFMR B is still only 51.4 percent of nominal (SWC open) for this fault on Line 1. This number is unacceptable if the critical voltage threshold is 70 percent. For the assumed transformer impedance, the maximum allowable secondary source impedance is 4.58 Ω.

Having two independent sources, as shown in Fig. 6, provides a solution to the problem of excessive source voltage drop. From Fig. 7, we see that the voltage on Lines 3 and 4 is unaffected by faults on Line 1 if SWC is open (shown dashed in Fig. 6). We intentionally dashed SWC because inclusion of this switch is optional. For this switch, consider the tradeoff of continuity of service versus voltage variation reduction. If the consequences of a lost source are greater than those of voltage sags for a line fault, then operate SWC normally closed, and open it for all detected line faults.

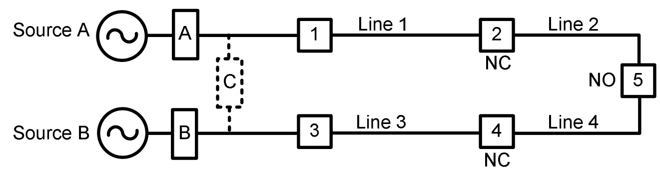


Fig. 6. System Single-Line Diagram (Independent Source Feed Example)

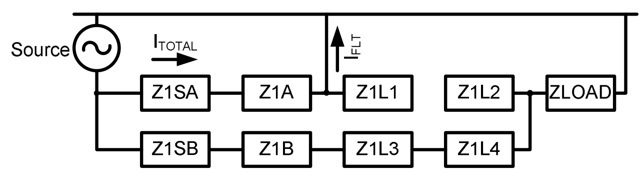


Fig. 7. Faulted System Sequence Connection Diagram (Independent Source Feed Example)

C. Communication Between Relays Reduces Tripping and Voltage Sag Times

Given the system shown in Fig. 8, coordination with the 50E fuse prohibits fast tripping for permanent main-line faults on Line 1: Relay 2 of the Recloser (R) must time-coordinate with the 50E fuse, and Relay 1 must time-coordinate with Relay 2.

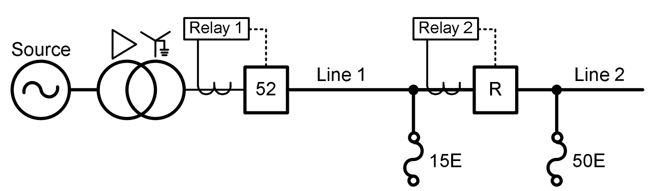


Fig. 8. System Single-Line Diagram of an Application Where Communications Improve Time Coordination

Fig. 9 shows the traditional time-current coordination curves for the system shown in Fig. 8. Notice that the time to clear a fault on the source side of the 15E fuse is delayed due to traditional time coordination.

Communications between Relays 1 and 2 reduce tripping time for Line 1 faults (i.e., Relay 1 no longer has to time-coordinate with Relay 2 if communications are present). Instead, Relay 1 now only has to time-coordinate with fuses tapped off of Line 1. With the proposed scheme, Relay 1 utilizes two time-overcurrent elements: one that coordinates with Relay 2 if the communications channel is not in-service and another that coordinates with the 15E fuse when the channel is available.

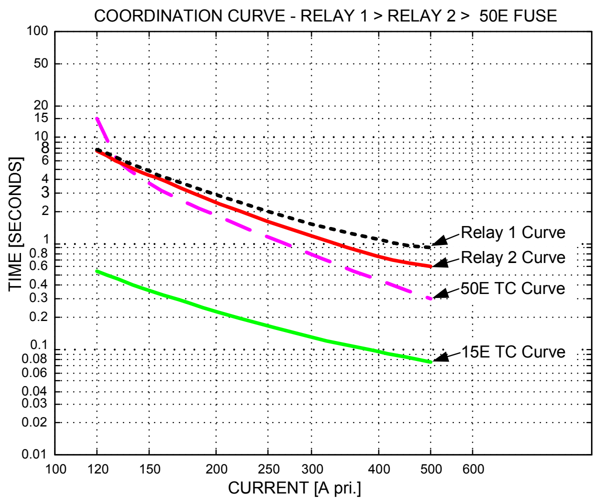


Fig. 9. Time Coordination Can Aggravate Power Quality for Line 1 Faults

The communications channel and the supporting logic in Relays 1 and 2 permit Relay 1 to discern when a fault is downstream from Recloser R. For faults downstream from Recloser R, Relay 2 senses the fault and instructs Relay 1 to not trip by its fast time-overcurrent element. If Relay 2 does not sense a fault in the forward direction while Relay 1 does, then the fault must be on Line 1 or on a Line 1 lateral. For such faults, Relay 1 does not receive a block signal and is permitted to trip by its fast time-overcurrent element (remember that Relay 1 knows that Relay 2 and the channel are in-service via the unique communications logic described in [2]). With this scheme, Relay 1 is only required to time-coordinate with the 15E fuse.

Fig. 10 illustrates the improvement in relay tripping times afforded by the addition of a communications channel and associated logic. The benefits afforded by this improvement in tripping speed are:

1. Less voltage sag duration for the power system surrounding the faulted Line 1.
2. Less equipment damage.

When either Relay 2 or the communications channel fails, Relay 1 switches to an alternate setting group. The settings in this alternate group switch the protection time coordination of Relay 1 to that shown in Fig. 9.

An additional motivation for installing communications between Relays 1 and 2 is the ability to have system protection in the event that Recloser R fails for high-impedance ground faults at the end of Line 2. If Relay 2 detects a recloser trip failure for a fault, it sends a direct transfer trip signal to Relay 1. Trip failures for manual or supervisory trip commands need not trip SW1 (and created an unscheduled outage for that load served by the 15E fuse).

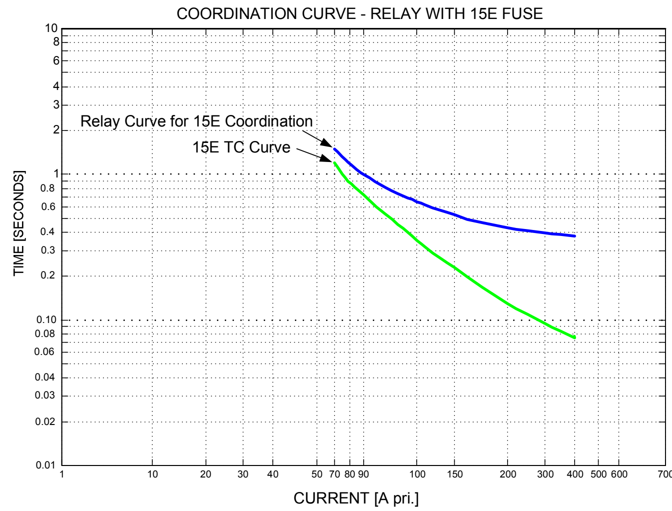


Fig. 10. Improved Time Coordination Afforded by Relay 1 to Relay 2 Communications Permits Faster Tripping for Line 1 Main-Line Faults

D. Conventional Means of Reducing Tripping and Restoration Times

1) Load Encroachment Logic Reduces Three-Phase Fault Tripping Times

For heavily loaded feeders, traditional nondirectional phase overcurrent elements (and the associated setting philosophy) require settings pickups higher than the maximum load magnitude to avoid tripping for load. The major drawbacks of this protection philosophy are reduced sensitivity and increased trip time for main-line faults.

Today, we can use load encroachment (LE) logic to torque-control the phase protection. The LE logic picks up whenever it detects load (i.e., the relay detects that the measured positive-sequence impedance lies with the load region shown in Fig. 11). If the LE logic picks up, the phase overcurrent elements are blocked until the positive-sequence impedance moves outside of the load region. Using this LE logic, we can securely set the pickup of phase overcurrent elements below load current magnitudes to increase sensitivity. This also allows closer coordination with downstream devices. (This is the same load encroachment logic used to give mho distance element security for heavily loaded transmission lines.) Closer time coordination reduces tripping times. Fig. 12 shows how a load encroachment element defines the load out of the line terminal.

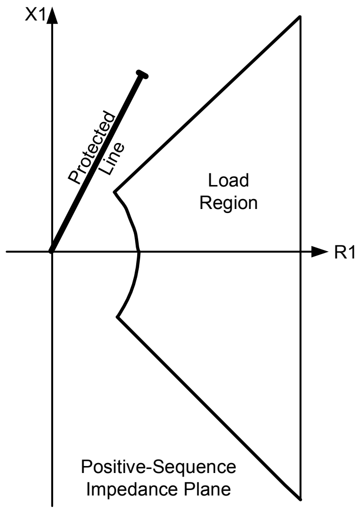
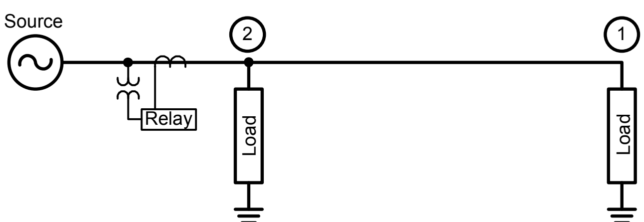


Fig. 11. Load Encroachment Characteristic Surrounds Load Region

Let us next examine two load placement scenarios as a means of demonstrating the effectiveness of the LE logic to differentiate load and three-phase fault conditions. Fig. 12 shows the two load placements we considered: load at ① for Case 3, and load at ② for Case 4. In these case examples, we use secondary values to relate them to what a relay would measure.



Secondary Values: E = 66.4 V ∠0° Z_{1S} = 1 Ω ∠90° Z_{1L} = 8 Ω ∠60°

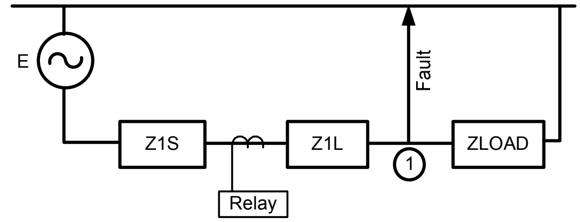
Fig. 12. Single-Line Diagram Showing Load Placements in Case Studies of Load Influence on Pos.-Seq. Impedance Measured by Relay Before and During Three-Phase Faults

a) Case 3: Load Concentrated at Line End (①)

For this case, we assume ZLOAD = 8 Ω ∠0°. Thus, the relay simply measures a positive-sequence impedance (Z1) equal to (Z1L + ZLOAD =) 13.85 Ω ∠30°. This impedance is inside the LE characteristic, and the LE logic picks up to block the phase overcurrent protective elements.

Now let us examine Z1 measured by the relay for an end-of-line (EOL) three-phase fault. Because the fault shorts-out the load impedance, the relay measures Z1L: 8 Ω ∠60°.

Thus, we see that there is an appreciable difference in the magnitude and angle of Z1 for load and three-phase fault conditions.



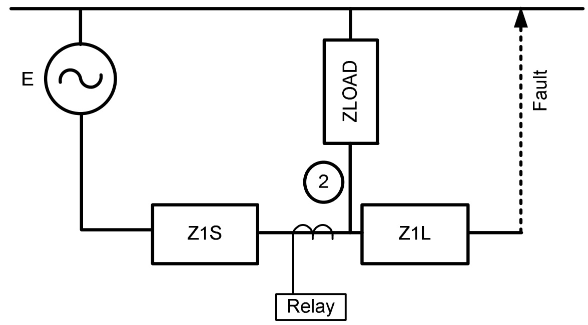
Secondary Values: E = 66.4 V ∠0° Z_{1S} = 1 Ω ∠90° Z_{1L} = 8 Ω ∠60°

Fig. 13. Positive-Sequence Network Connection Diagram for Case 3

b) Case 4. Load Concentrated Near the Substation (②)

Let us now address the concern that the $|I_1|$ for load and an EOL three-phase fault are equal. For load conditions, the relay measures a positive-sequence impedance (Z1) equal to ZLOAD.

Now let us examine Z1 measured by the relay for an EOL fault. Because the fault does not short-out the load impedance but instead places the line impedance in parallel with the load, the relay measures Z1 = 4.62 Ω ∠30°. Again we see that there is an appreciable difference between Z_1 for load and three-phase fault conditions.



Secondary Values: E = 66.4 V ∠0° Z_{1S} = 1 Ω ∠90° Z_{1L} = 8 Ω ∠60°

Fig. 14. Positive-Sequence Network Connection Diagram for Case 4

What if we did not consider load in the fault calculations and assumed that the line impedance and load impedance magnitudes were equal? For such a scenario, ∠Z1 measured by the relay for faults and load would only differ by the difference in angles between the line and load. However, we must consider the parallel combination of load and line impedances to determine Z_1 measured by the relay for line faults combined with load.

E. New Logic Avoids Raising Settings for Evolving Fault Considerations (Patent Pending)

Evolving faults can cause time-coordination difficulties when the evolving fault is on the load side of a power fuse. In the following example, we describe a fault that evolves as viewed by relay (i.e., the relay senses a change in fault type). but from the power system viewpoint it is a multiphase-to-ground fault on a radial line that clears sequentially.

Let us examine an evolving BCG fault on the load side of the 50E fuse shown in Fig. 15. Please note that the evolving faults we are concerned about here are those that evolve from phase-to-phase-to-ground to single-line-to-ground.

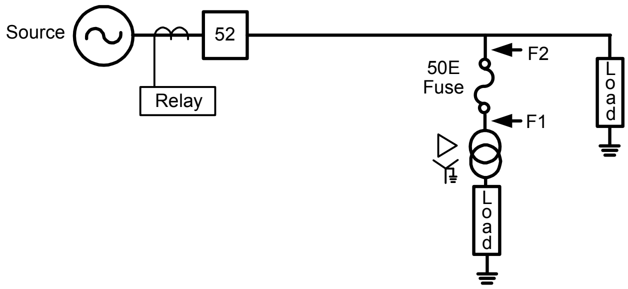


Fig. 15. System Single-Line Diagram for Evolving Fault Case Studies

For the BCG fault location shown as F1 in Fig. 15, the B-phase fuse clears first in 0.47 second, given 414 A. The B- and C-phase fuses do not blow simultaneously because the B-phase fuse carries considerably more current than the C-phase fuse does.

For the C-phase current shown in Table III, the 50E fuse has not reached its minimum melt time when the B-phase fuse clears. However, this fuse has heated 58 percent towards minimum melt. Once the B-phase fuse clears, the magnitude of current presented to the C-phase fuse decreases slightly, but the residual current measured by the relay nearly doubles.

TABLE III
FAULT CURRENTS FOR EVOLVING FAULT AT F1 IN FIG. 15

Current Designation	BCG Fault [A pri.]	CG Fault [A pri.]
I_C	261	251
$3I_0$	162	330

The fault scenario described above presents a coordination difficulty for the relay because the ground time-overcurrent (TOC) element begins to time for the BCG fault and does not cease to time until after the C-phase fuse interrupts the fault.

For this case, the ground TOC uses an extremely inverse characteristic with a pickup setting of 50 A primary and a time dial of 4.8. With this pickup and time-dial setting, the minimum coordination margin is 0.2 seconds at the maximum ground fault duty of 300 A at fault location F2.

For the initial BCG fault, the ground TOC senses the fault and times for 0.475 seconds or approximately 16 percent of its total timeout. Once the B-phase fuse interrupts, this TOC element continues to time. Because the ground TOC element has a "head start" on the C-phase fuse, we effectively are attempting to coordinate a 50E fuse ("pre-heated" to 58 percent of its total interrupt energy) and a ground TOC element with a pickup of 50 A and a time dial of 4. The operate time for such an element is 0.68 seconds for the CG fault values shown in Table III. The interruption time for the C-phase fuse is 0.77 seconds. The result of fault evolution for this example is a miscoordination of 0.09 seconds. Coordination is restored on the reclose if the ground TOC element is completely reset. However, this miscoordination results in an additional voltage dip to the power system if the relay tests the line and the C-phase fuse has not completed melting.

1) Simple Means of Resolving Evolving Fault Miscoordination

The easiest means of resolving this miscoordination is to increase the ground TOC time dial. However, doing this results in longer clearing times for main-line faults. This also means longer voltage sags.

Protective relaying schemes using ground distance elements to detect faults along the protected line must have Fault Identification and Selection (FIDS) logic, which dependably distinguishes fault type for both simple and complex faults. For transmission line applications, this logic is required for distance element control for multiphase-to-ground faults and for single-pole trip security. This same logic is also useful for improving coordination of distribution protection systems for evolving faults.

a) FIDS Introduction (Patented)

The FIDS logic first compares the phase angle between I_{A2} and I_{A0}. The fault type is A-ground if the angle difference between I_{A2} and I_{A0} is 0° ±60°, B-ground if the angle difference is 120° ±60°, and C-ground if the angle difference is –120° ±60°. In the FIDS logic, these ±60° sectors are referred to as FSA, FSB, and FSC, respectively.

Fig. 16 illustrates the phase angle relationship between I_{A2} and I_{A0} for ground faults. Fig. 17 illustrates the comparison of this angle for an A-ground and a BC-ground fault without fault resistance.

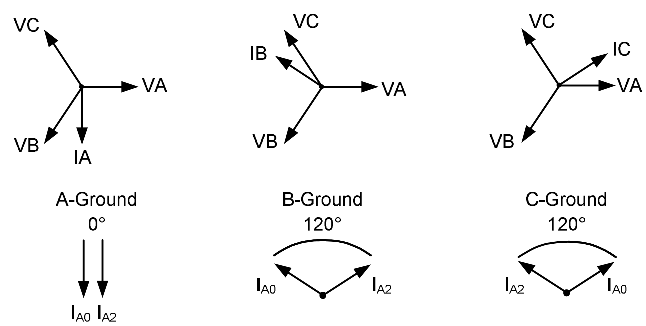


Fig. 16. Angle Relationship of I_{A2} and I_0 for Single-Line-to-Ground Faults

In Fig. 17, the angle between I_{A2} and I_{A0} are the same (0°) for both fault types.

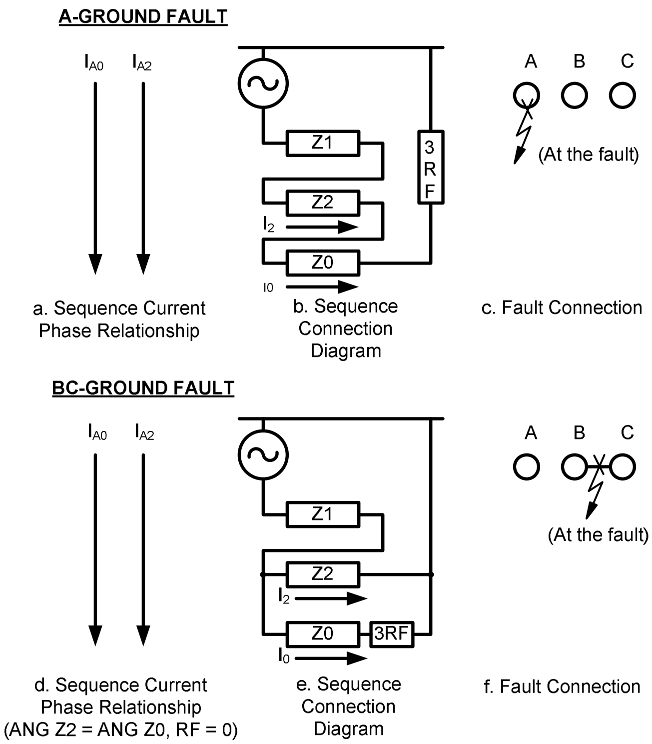
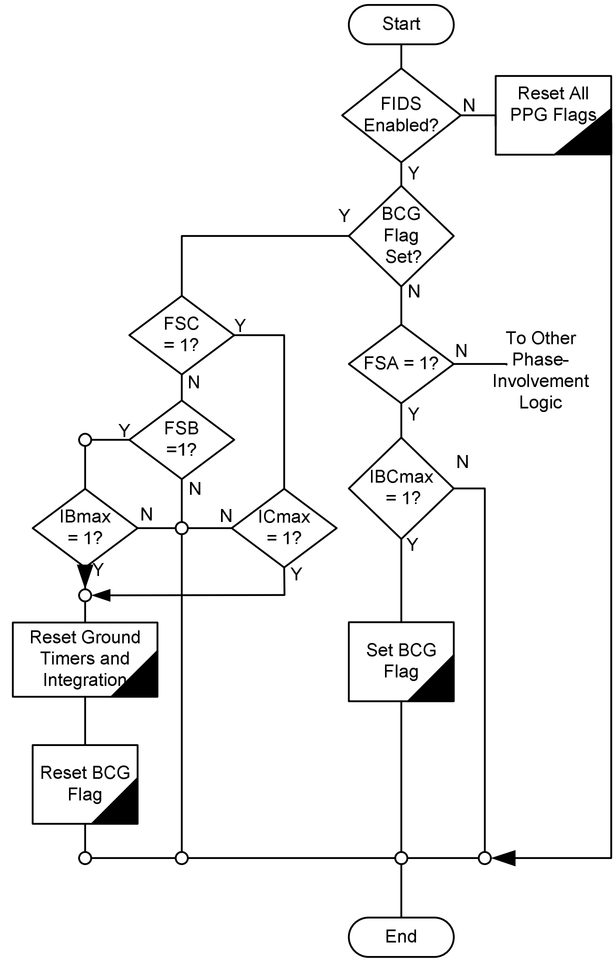


Fig. 17. Angle Relationship of I_{A2} and I_0 for A-Ground and BC-Ground Faults

Combining this FIDS logic with maximum phase and phase-to-phase current identification logic forms a scheme that identifies the evolving fault described earlier. For this fault, FSA asserts, and the BC current is the highest phase-to-phase current. When the B-phase fuse interrupts, the FIDS logic output changes to FSC while C-phase current is the highest phase current.

Because FIDS gives the same output for two different fault types (e.g., FSA asserts for A-ground and BC-ground faults), the fault evolution logic requires maximum phase and phase-phase current knowledge to give additional fault type differentiation.

Fig. 18 shows the new fault evolution logic for detecting the evolution of a BC-ground to either C- or B-ground. When the logic detects the evolution of a phase-to-phase-to-ground fault to a single-line-to-ground fault, all ground time-overcurrent element timing resets. This resetting of the timing in effect resets the ground TOC timing and restores coordination (after resetting, the ground TOC element renews its timing towards timeout).



Legend:

FIDS	Fault identification and selection logic
FSA	Fault selection logic selects A-phase
FSB	Fault selection logic selects B-phase
FSC	Fault selection logic selects C-phase
IBmax	B-phase is the max. phase current
ICmax	C-phase is the max. phase current
IBCmax	BC is the max. phase-to-phase current

Fig. 18. Flow Diagram of Evolving Fault Detection Logic (BCG to B- or C-Phase Portion, Other Fault Evolution Logic Similar)

V. Implementation of Schemes

Let us next describe the details of implementing the protection and control schemes referred to earlier in this paper. For this next section, we use the following single-line diagram:

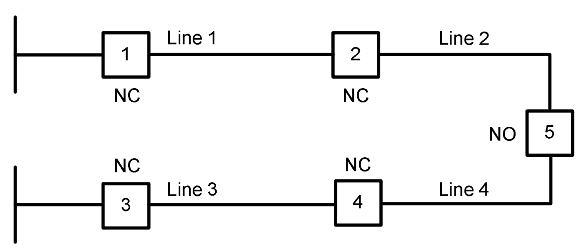


Fig. 19. One-Line Diagram With SW1 – SW4 Normally Closed, and SW5 Normally Open

Tables IV and V show the switch operations required to restore load to as much of the connected load as possible for various fault placements (FLS in these tables = faulted line section).

TABLE IV
OPERATIONS WITH SW1, SW2, SW3, AND SW4 CLOSED, SW5 OPEN

FLS	SW1	SW2	SW3	SW4	SW5
1	Open	Open	No	No	Close
2	No	Open	No	No	No
3	No	No	Open	Open	Close
4	No	No	No	Open	No

TABLE V
OPERATIONS WITH SW1, SW3, SW4, AND SW5 CLOSED, SW2 OPEN

FLS	SW1	SW2	SW3	SW4	SW5
1	Open	No	No	No	No
2	No	No	No	No	Open
3	No	Close	Open	Open	No
4	No	Close	No	Open	Open

A. Conventional Restoration Scheme Using Relays/Controls and VTs

Restoration of distribution load is still performed manually at many utilities. Personnel operate switches and other sectionalizers until the faulted line is isolated. Some utilities are adding radios or other communications links to perform close/open operations remotely.

Another means of reducing restoration times and directly improving traditional reliability data (SAIDI, CAIDI) is to use conventional microprocessor-based relays and/or recloser controls at each switch location with voltage signals supplied from voltage transformers at each side of the switch. This enables us to detect hot/dead voltage conditions, thereby allowing automatic tripping and restoration of switches, improving speed and reliability. To test this approach, let us consider the system shown in Fig. 20 with the following characteristics:

- Switches SW1 and SW3 have fault interrupting capability. Switches SW2, SW4, and SW5 can only interrupt load safely.
- Switches SW1 and SW3 have relays or controls with instantaneous and time-overcurrent protection (50/51) and three-shot automatic reclosing.
- Switches SW2, SW4, and SW5 have controls that have instantaneous overcurrent (50), under- and overvoltage elements (27 and 59, respectively), programmable logic, and internal timers.

By using these capabilities, we reduce restoration times on nonfaulted lines from minutes (manual restoration) to seconds.

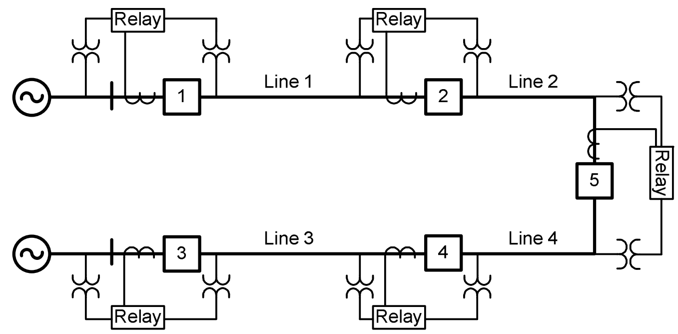


Fig. 20. One-Line Diagram of Conventional Restoration Scheme Using Relays and Voltage Transformers

In this example, each relay uses voltage elements to declare dead or hot voltage (e.g., “DL2” indicates “dead voltage on Line 2” and “HL4” indicates “hot voltage on Line 4”). Consider a permanent fault on Line 1: SW1 detects the fault and trips by overcurrent protection (50/51). The scheme initiates Line 2 restoration when the line is de-energized on either side of SW2, provided that:

1. Voltage was initially hot on both sides of SW2 (HL1 • HL2).
2. Voltage goes dead (DL1 • DL2).
3. SW2 is closed.
4. A 50 element at SW2 is not picked up (a security guard for bolted three-phase faults).
5. Conditions 1 through 4 are true for tt2 time (which is greater than the maximum total reclosing time for SW1). The 50 element at SW2 picked up and dropped out twice, and conditions 1 through 4 are true for tt2 time (which is less than the third reclosing interval at SW1). Then trip SW2.

The logic shown for this scheme in Fig. 21 ensures that Line 2 restoration is only attempted if the line voltages on both sides of the switch are initially healthy, followed by dead voltages on both sides of the switch. SW2 must be closed to trip. By checking the status of the 50 element for SW2, we ensure that SW2 does not attempt to interrupt fault current. If the fault is on Line 1, we trip SW2 after SW1 has completed its reclosing sequence. If the fault is on Line 2, we trip SW2 before SW1 advances to lockout. Set tt2 greater than the longest reclosing sequence at SW1 (about 90 to 120 seconds). Set tt2a less than the third reclosing open interval at SW1 (e.g., 5 to 10 seconds).

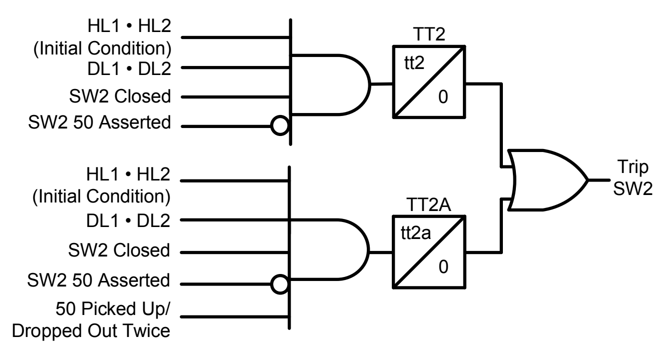


Fig. 21. Tripping Logic for SW2 – Conventional Restoration Scheme

The closing logic for SW5 requires the following conditions be true for tc5 time:

1. Voltage is initially hot on both sides of SW5 (HL4 • HL2).
2. Voltage goes dead on Line 2 (HL4 • DL2).
3. SW5 is open.
4. SW5 did not trip after a restoration close attempt.

The logic for closing SW5 is shown in Fig. 22.

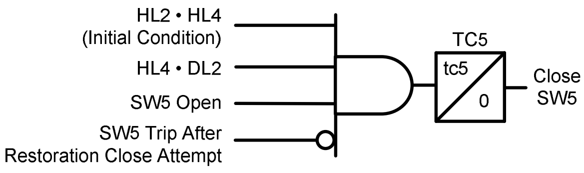


Fig. 22. Closing Logic for Switch SW5 – Conventional Restoration Scheme

This logic ensures that we have "healthy" voltages before Line 2 goes dead and the scheme automatically restores. Moreover, the scheme only attempts one restoration close. If SW5 trips after a restoration close attempt, the logic blocks closing. We set our time delay (tc5) greater than the longest delay for tripping SW2 (e.g., 120 to 150 seconds).

Finally, if the fault on Line 2 is permanent, we need to avoid another reclosing sequence from SW3 after SW5 has been closed. Thus, if the voltages go dead (DL2 • DL4) after a close attempt by SW5, the logic trips SW5 before SW3 recloses.

The logic for this scheme is shown in Fig. 23.

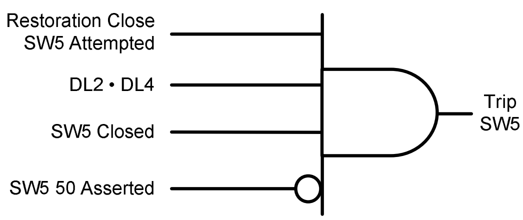


Fig. 23. Tripping Logic for Switch SW5 – Conventional Restoration Scheme

Generally, we set the "dead" voltage threshold at 10 to 20 percent of nominal to ensure voltage at or near zero and "hot" voltage settings at 80 to 90 percent of the nominal line voltage.

Figs. 24 and 25 show timing sequences for permanent faults on Line 1 and 2, respectively.

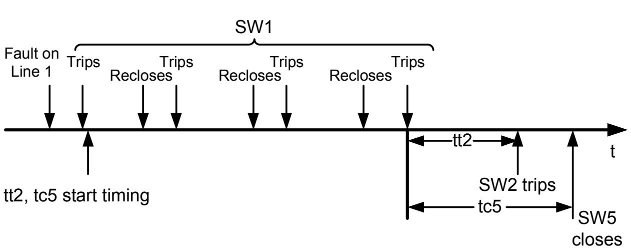


Fig. 24. Line 1 Permanent Fault Timing – Conventional Restoration Scheme

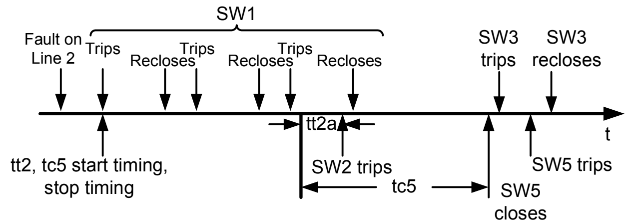


Fig. 25. Line 2 Permanent Fault Timing – Conventional Restoration Scheme

A few other observations on this scheme:

- Logic can be applied to SW4 similar to that of SW2.
- SW1 and SW3 must delay the first reclose to allow SW5 to trip (e.g., 0.5 seconds).
- Restoration conditions should be modified based on the distribution system. For example, if Line 2 is mostly underground, we may wish to trip SW2 after the first trip of SW1 to avoid automatic reclosing into a cable fault.

Overall, this scheme greatly improves restoration times on the distribution system compared to manual restoration (1 to 2 minutes versus 1 hour). One disadvantage is that we still have long voltage sags, which affect other loads on the surrounding feeders. Also, by always closing Switch SW5, we risk closing into a permanent fault on Line 2.

B. Use Communications Channels for Fast Fault Clearing and Load Restoration

Using the conventional scheme described above, we improve the reliability measures SAIDI and CAIDI by reducing restoration times. However, as we discussed earlier in the paper, using intelligent relays or recloser controls linked together by communications channels reduces voltage sag and swell times for more critical and sensitive loads.

Now let us examine how we can implement these improvements. For the following discussion, we use the one-line diagram shown in Fig. 26.

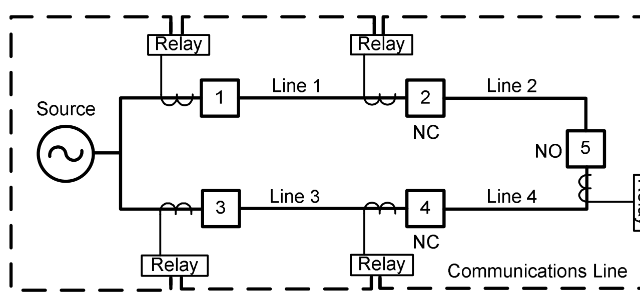


Fig. 26. One-Line Diagram of Communication-Enhanced Restoration Scheme

Switches SW1 through SW5 are equipped and operated as follows:

- Each switch is a recloser with fault-interrupting capability.
- Each "relay" is a recloser control equipped with relay-to-relay communications logic.

- Each recloser control can communicate to one or two other recloser controls. This can be accomplished by using point-to-point 900 MHz radios at each location or by another media (e.g., optical fiber, phone lines). This establishes communications lines between all five switches (SW1 through SW5).

For each switch, we apply three reclose attempts. Where possible, we switch load after the initial fault to reduce "blinks" on unfaulted portions of the feeder.

To restore load as quickly and intelligently as possible, the protection system needs the following information at each switch:

- What switches are initially open or closed?
- Which relays sensed the fault?

By using relay-to-relay communications, we can distribute this information. Fig. 27 shows an example of how the communications take place.

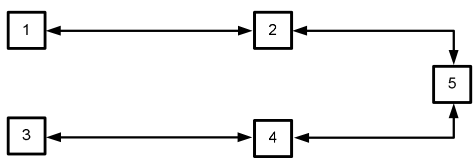


Fig. 27. Communications Links Using Relay-to-Relay Communications Logic

In this arrangement, SW1 communicates with SW2, SW2 with SW1 and SW5, SW5 with SW2 and SW4, SW4 with SW5 and SW3, and SW3 with SW4. Each communications link can send and receive up to 8 "bits" of information. This can be increased to 16 bits using two channels (two radios, fibers, etc.) between each pair of switches. Therefore, SW1 can receive information from SW2, which can send its own data plus pertinent data received from SW5, and so on.

Because the communications channel is rapid, each relay knows the status of each logic point within a few cycles of any fault initiation. This capability allows the scheme to trip the affected portions of the feeder in a few cycles and restore the remainder of the feeder a few cycles later.

As an example, using optical fiber, the data can be transmitted and received between each device in about 0.5 cycle. With radios, this time is 1.0 to 1.5 cycles. The final trip and close decision is made at the relay for each switch, but it uses logic points from the other relays as "permissive" or "block" conditions for tripping and closing.

Now let us examine some specific examples of how we can apply improved trip and restoration logic.

1) Switches SW1 Through SW4 Closed and SW5 Open

With the circuit arrangement of the distribution network shown in Fig. 28, we need to implement logic that isolates the faulted portion of the system as quickly as possible. One way to think of it is that we wish to "quarantine the sick." We show logic for switches SW1 and SW2 below, but similar logic can be implemented on SW3 and SW4.

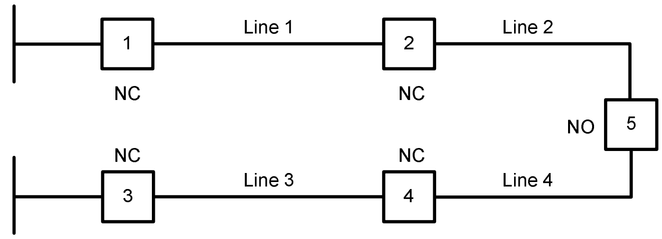


Fig. 28. One-Line Diagram With Switches 1 Through 4 Closed and Switch 5 Open

For the fault on Line 1, we wish to isolate that line section and restore load to Line 2 as quickly as possible. We first trip SW1 using an instantaneous overcurrent element (50) with a "fast" time curve, provided the fast curve can be applied without miscoordination. If the fault is on Line 2, an instantaneous overcurrent element at SW2 (50) "blocks" the fast curve at SW1, as long as the communications channel is established. We also enable the fast curve at SW1 if SW2 is open. Fig. 29 shows the logic:

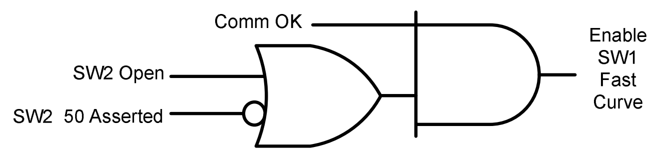


Fig. 29. SW1 Fast Curve Tripping Logic – Communications-Enhanced Scheme

We wish to open SW2 quickly for the following conditions:

1. Communications are OK.
2. The instantaneous overcurrent (50) at SW1 picked up initially ("rising edge" of 50).
3. The SW1 50 is not presently asserted.
4. SW1 is open.

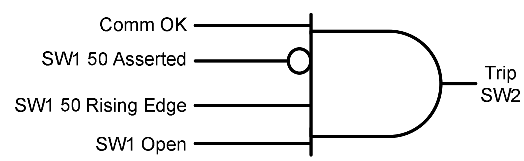


Fig. 30. Logic for Tripping SW2 for Fast Restoration of Line 2 Load Using Communications-Enhanced Scheme

The output of the logic shown in Fig. 30 can be transmitted to SW2 within 1 to 2 cycles to trip SW2.

Next, we wish to restore load to Line 2 as quickly as possible. SW5 is closed for the following conditions:

1. Communications are OK.
2. The instantaneous overcurrent (50) at SW1 picked up initially ("rising edge" of 50).
3. The SW2 overcurrent element (50) has not picked up.
4. SW2 is open.

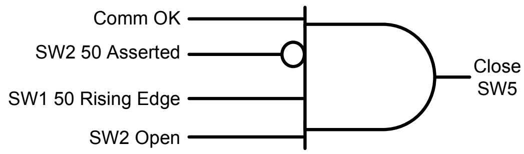


Fig. 31. Logic for Closing SW5 for Fast Restoration for Line Load Using Communications-Enhanced Scheme

This logic ensures that SW1 senses the fault and SW2 does not, before closing SW5. We need only wait for SW2 to open and for the logic points to be transmitted. The logic is shown in Fig. 31. Finally, we enable fast tripping at SW2 if communications are OK and the SW5 is either open or the SW5 "50" device is not asserted, the logic for which is shown in Fig. 32.

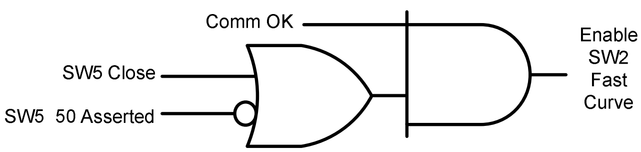
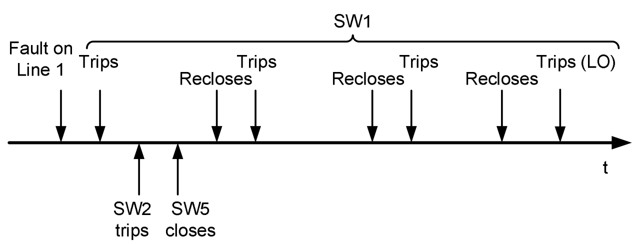
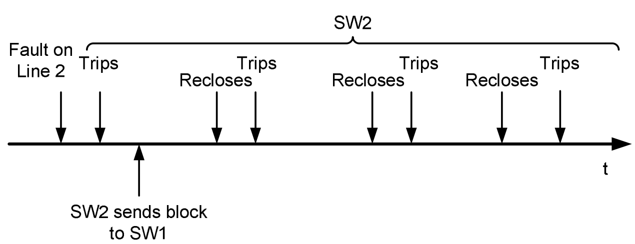


Fig. 32. SW2 Fast Curve Tripping Logic – Communications-Enhanced Scheme

Now let us examine the operations for some system faults. Fig. 33 shows the timing diagrams for faults on Line 1 and Line 2, using fast clearing communications-enhanced logic.



a. Fault on Line 1



b. Fault on Line 2

Fig. 33. Timing for Permanent Faults – Communications-Enhanced Scheme.

We can implement automatic restoration logic for virtually any combination of initial switch positions. We use the switch positions to change settings groups at each relay/recloser control. Thus, we implement a different series of trip/close conditions.

C. Changing Settings to Adjust to System Conditions

Another means of achieving faster fault clearing is to use settings groups based on switch position. As long as communications are established, we can automatically or manually change time-overcurrent and instantaneous tripping at each switch, thus reducing or eliminating miscoordination. If communications are lost, we can revert to "normal" relay settings (SW1, SW2, SW3, SW4 closed, SW5 open).

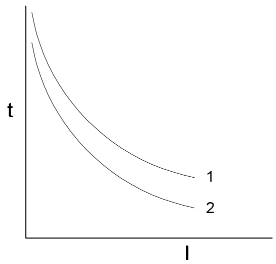
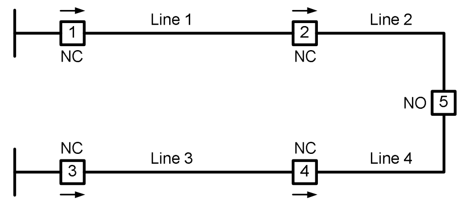
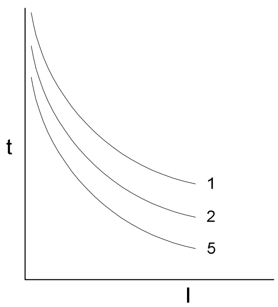
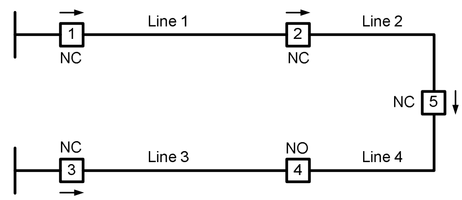
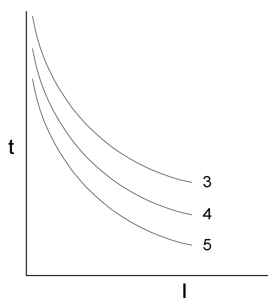
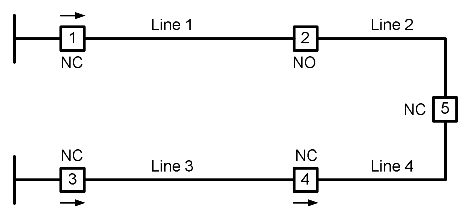
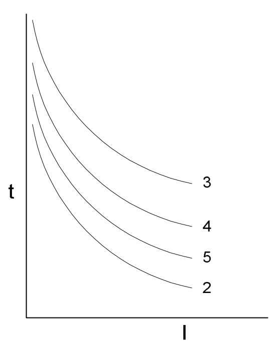
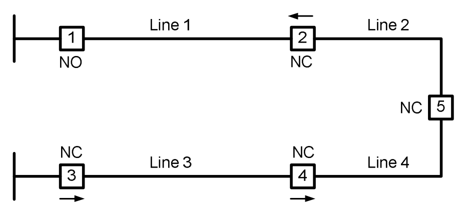
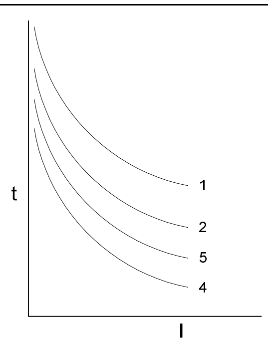
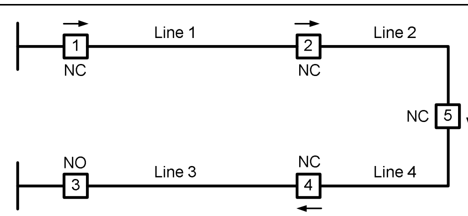
D. Control Schemes to Meet the Needs of Those 25th Percentile Customers

In the scheme logic discussed thus far, we have not restored full voltage service to Line 2 load within 10 cycles for Line 1 faults. To accomplish this, we need to open SW2 and close SW5 for any Line 1 fault.

When the SW1 relay senses a fault and SW2 does not, the fault location is confined to somewhere on Line 1. Using the communications channel and associated logic, SW1 transmits the status of its fault-detection elements to SW2. Upon receiving the message from SW1 that it senses a fault, SW2 then checks the status of its own fault detecting elements. If none are picked up, then SW2 trips. The overcurrent elements at SW1 and SW2 can be supplemented with directional elements for those circuits prone to sympathetic tripping [5]. Simultaneous to tripping, the relay for SW2 transmits a close signal to SW5.

Given that the protective relay pickup time and end-to-end channel time are both less than 1 cycle, we issue a trip for SW2 within 2 cycles from fault initiation. SW5 receives a close signal within 3 cycles of fault initiation (we assume that close-to-open time of SW2 is less than the open-to-close time of SW5). Thus, given a 7-cycle close time for SW5, we successfully restore Line 2 load for any Line 1 fault. If the close-to-open time of SW5 is greater than 7 cycles, we need to review decreasing the time required for SW5 to receive the close signal. Faster pickup overcurrent elements (approximately 0.25 cycle) and faster communications channels (i.e., using a fiber-optic channel and a baud rate of 19,200 kbits/sec., the end-to-end channel delay is 4 ms.) can reduce the 3-cycle delay for SW5 to close to 0.75 to 1.0 cycle. Employing these faster techniques allows the open-to-close times for SW5 to approach 9 cycles.

TABLE VI
COMMUNICATIONS PERMIT TIME COORDINATION TO MATCH SYSTEM SWITCHING

Time Curve Coordination	SW1	SW 2	SW 3	SW 4	SW 5	One Line of Switch Positions
	CL	CL	CL	CL	OP	
	CL	CL	CL	OP	CL	
	CL	OP	CL	CL	CL	
	OP	CL	CL	CL	CL	
	CL	CL	OP	CL	CL	

VI. Summary

Important points presented in this paper include the following:

1. Using communications-assisted protection and control schemes for distribution circuits significantly reduces trip and load transfer times.
2. Traditional performance indices do not consider the reduction in service reliability caused by fault-induced voltage sags. Considering the effects of these sags on customer loads in the immediate vicinity of a fault, we conclude that we must also consider new protection and control methods, which reduce sag duration to cycles instead of seconds.
3. Fault tree analysis shows that upgrading breaker and recloser controls with communications scheme logic realized a 40 percent improvement in service unavailability (as compared to traditional distribution protection and control).
4. Communications-assisted trip logic simplifies difficult time-coordination applications by limiting the number of devices requiring coordination. This simplification also decreases tripping time for main-line faults.
5. The same load encroachment logic used for transmission line distance element security increases distribution protection sensitivity, while allowing closer time coordination with downstream devices.
6. We showed that phase-to-phase-to-ground faults on the load side of a heavily loaded lateral can cause ground overcurrent element miscoordination. We present new logic that avoids having to raise ground element settings to maintain coordination.
7. We showed that, without a communications channel, we can apply relay logic that combines voltage elements, switch status, and other combinatorial logic to improve service reliability for nonfaulted feeders served by a faulted source.

VII. References

[1] ANSI/IEEE Std 493-1990, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems, Chapter 2.

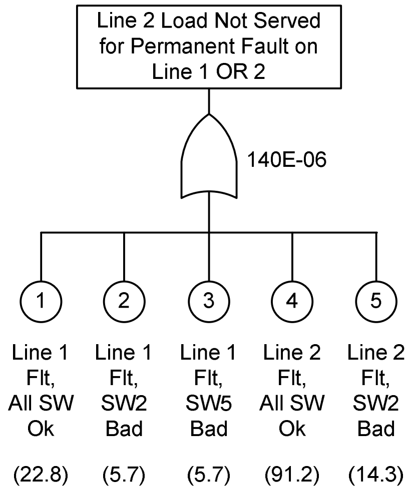
[2] Kenneth C. Behrendt, "Relay-to-Relay Digital Logic Communication for Line Protection, Monitoring, and Control," 51st Annual Georgia Tech Protective Relaying Conference, Atlanta, Georgia, May 1997.

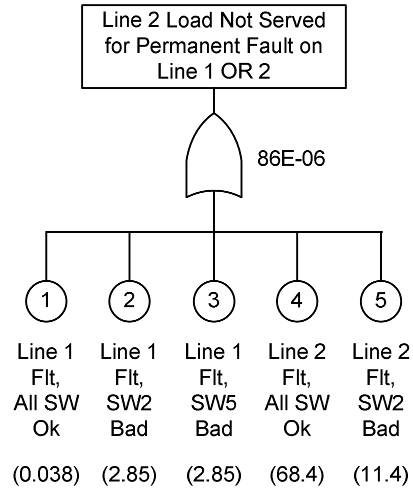
[3] CBEMA Curve Application Note, Technical Committee #3 (TC-3) of the Information Technology Industry Council (ITI), 1996.

[4] James J. Burke, *Power Distribution Engineering: Fundamentals and Applications*, 1st Edition, 1994. Published by Marcel Dekker, Inc., 270 Madison Avenue, New York, NY, 10016.

[5] Jeff Roberts, Terrence L. Stulo, and Andres Reyes, "Sympathetic Tripping Problem, Analysis and Solutions," 24th Annual Western Protective Relay Conference, Spokane, Washington, October 1997.

APPENDIX I





UNAVAILABILITY OF SERVING LINE 2 LOAD FOR SYSTEM USING MANUAL ISOLATION SWITCHES

①. Line 2 Load not served for Line 1 faults for (½ + ½) 1 hr every 5 yrs.

= λ • MTTR
= 0.2 • (2 • 0.000057)
= 22.83E-06

(½ hr to operate each switch)

②. Line 2 load not served for Line 1 faults and SW2 bad for (½ + 1 + ½) 2 hrs every 5 yrs. On average, SW2 is tested every 2.5 yrs, given that Line 1 and Line 2 faults every 5 yrs. Of this 2.5 yrs, SW2 available ½ the time for a λ = 1/40 (calc. as (1.25/10 • (1/5)).

= λ • MTTR
= 1/40 • (2 • 0.000114)
= 5.7E-06

(½ hr travel to SW2, 1 hr line repair, ½ hr travel to SW2)

③. Same as ② above.

④. Line 2 load unserved for (½ + 3 + ½) 4 hrs for Line 2 fault, and all switches ok.

= λ • MTTR
= 0.2 • (4 • 0.000114)
= 91.2E-06

(½ hr travel to SW2, 3 hrs line repair, ½ hr SW2 travel)

⑤. Line 2 Load unserved for (½ + 3 + 1 + ½) 5 hrs for Line 2 fault and SW2 bad.

= λ • MTTR
= (1/40) • 0.2 • (5 • 0.000114)
= 14.3E-06

(½ hr travel to SW2, 3 hrs line repair, ½ hr SW2 travel, 1 hr line repair)

Note: MTTR has units of years: ∴ 1 hr = 0.000114 yr.

UNAVAILABILITY OF SERVING LINE 2 LOAD FOR SYSTEM USING AUTOMATIC ISOLATION SWITCHES

①. Line 2 load not served for Line 1 faults for 6 seconds every 5 yrs.

= λ • MTTR
= 0.2 • (0.19E-06)
= 0.038E-06

(5 second open int. + 1 second comm.) = 0.19E-06

②. Line 2 load not served for Line 1 faults and SW2 bad for 1 hr every 5 yrs. Same λ = 1/40 justification as that for ② to the left.

= λ • MTTR
= 1/40 • (2 • 0.000114)
= 2.85E-06

(nearly inst. detect, 1 hr repair)

③. Same as ② above.

④. Line 2 load unserved for ≅ 3 hrs for Line 2 fault and all switches ok.

= λ • MTTR
= 0.2 • (3 • 0.000114 + 0.19E-06)
= 68.4E-06

(3 hr line repair, 6 second locate and automatically isolate)

⑤. Line 2 load unserved for ≅ 4 hrs for Line 2 fault and SW2 bad.

= λ • MTTR
= 0.2 • (4 • 0.000114 + 0.19E-06)
= 11.4E-06

(3 hr line repair, 1 hr switch repair, 6 second locate and automatically isolate)